SOUTHERN ENVIRONMENTAL LAW CENTER

525 East Bay Street, Suite 200
Charleston, SC 29403

Telephone 843-720-5270
Facsimile 843-414-7039

March 15, 2022

VIA ELECTRONIC FILING

The Honorable Jocelyn G. Boyd
Chief Clerk/Administrator
Public Service Commission of South Carolina
101 Executive Center Drive
Columbia, South Carolina 29210

In Re: Annual Review of Base Rates for Fuel Costs for Dominion Energy South Carolina, Incorporated (For Potential Increase or Decrease in Fuel Adjustment)
Docket No. 2022-2-E

Dear Ms. Boyd:

Please find attached for electronic filing the Direct Testimony and Exhibits of R. Thomas Beach, filed on behalf of the South Carolina Coastal Conservation League and Southern Alliance for Clean Energy in the above-referenced docket. Please contact me if you have any questions regarding this filing.

Sincerely,

s/Kate Mixson
Southern Environmental Law Center
525 East Bay Street, Suite 200
Charleston, South Carolina 29403
Telephone: (843) 720-5270
Facsimile: (843) 414-7039
kmixson@selcsc.org

Counsel for South Carolina Coastal Conservation League and Southern Alliance for Clean Energy

STATE OF SOUTH CAROLINA

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:	)	
	)	
Annual Review of Base Rates for Fuel Costs of Dominion Energy South Carolina, Inc.	)	**DOCKET NO. 2022-2-E**

DIRECT TESTIMONY AND EXHIBITS OF

R. THOMAS BEACH

ON BEHALF OF

THE SOUTH CAROLINA COASTAL CONSERVATION LEAGUE and SOUTHERN ALLIANCE FOR CLEAN ENERGY

March 15, 2022

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I. INTRODUCTION AND QUALIFICATIONS

Q: PLEASE STATE FOR THE RECORD YOUR NAME, POSITION, AND BUSINESS ADDRESS.

A: My name is R. Thomas Beach. I am principal consultant of the consulting firm Crossborder Energy. My business address is 2560 Ninth Street, Suite 213A, Berkeley, California 94710.

Q: PLEASE DESCRIBE YOUR EXPERIENCE AND QUALIFICATIONS.

A: My experience and qualifications are described in the attached curriculum vitae (CV), which is **Exhibit RTB-1** to this testimony. As reflected in my CV, I have more than 40 years of experience on resource planning, rate design, and ratemaking issues for natural gas and electric utilities. I began my career in 1981 on the staff at the California Public Utility Commission (CPUC), working on the implementation of the Public Utilities Regulatory Policies Act, on the restructuring of California's natural gas industry, and as an advisor to three commissioners. Since leaving the CPUC in 1989, I have had a private consulting practice on energy issues and have appeared, testified, or submitted comments, studies, or reports on numerous occasions before the state energy regulatory commissions in many states. My CV includes a list of the formal testimony that I have sponsored in state regulatory proceedings concerning electric and gas utilities.

Q: PLEASE DESCRIBE MORE SPECIFICALLY YOUR EXPERIENCE ON AVOIDED COSTS AND ISSUES RELATED TO NET ENERGY METERING AND

THE COST-EFFECTIVENESS OF RENEWABLE DISTRIBUTED GENERATION AND OTHER TYPES OF DISTRIBUTED ENERGY RESOURCES (DERS).

A: I have worked on issues concerning the calculation of avoided cost prices throughout my career, including sponsoring testimony on avoided cost issues in state regulatory proceedings in Oregon, California, Idaho, Montana, Nevada, New Hampshire, North Carolina, and Vermont. With respect to benefit-cost issues concerning renewable distributed generation (DG), I have sponsored testimony on net energy metering (NEM) and solar economics in South Carolina and ten other states. Since 2013, I have co-authored benefit-cost studies of NEM or solar DG in Arkansas, Arizona, California, Colorado, New Hampshire, North Carolina, South Carolina, and Wyoming. I also co-authored the chapter on Distributed Generation Policy in America's Power Plan, a report on emerging energy issues, which was released in 2013 and is designed to provide policymakers with tools (including rate design changes) to address key questions concerning distributed generation resources. Finally, since 2007, I have sponsored testimony on rate design issues concerning solar DG and other types of DERs (such as electric vehicles) in general rate case proceedings in Arizona, California, Massachusetts, and Texas.

Q: HAVE YOU PREVIOUSLY TESTIFIED BEFORE THIS COMMISSION?

A: Yes. I appeared before this Commission in December 2014, sponsoring testimony in Docket No. 2014-246-E recommending the methodology to use to evaluate NEM in South Carolina, pursuant to Act 236. I sponsored testimony on behalf of The Alliance for Solar Choice. This proceeding resulted in Order No. 2015-194, which established the current NEM program and the process for establishing the "value stack" of the benefits (and certain costs) of DERs that is quantified in these fuel clause cases. More recently, I testified in Docket No. 2020-229-E on behalf of CCL, SACE, Upstate Forever, Vote Solar, the Solar Energy Industries Association, and North Carolina Sustainable Energy Association recommending that the Commission reject Dominion Energy South Carolina's ("DESC") proposed Solar Choice tariff, in part because the underlying methodology failed to fully value the benefits of distributed solar. In Order No. 2021-391, the Commission rejected DESC's proposed Solar Choice tariff in favor of a new tariff based on time-of-use (TOU) rates and a modest minimum bill, similar to my proposal. Significantly, Order No. 2021-391 found that "Witness Beach has demonstrated with his cost-benefit analysis that solar has benefits over the long-run, life cycle of distributed solar resources, and has therefore indicated that the portions of the Joint Solar Choice Proposal approved in this Order will not cause a significant cost-shift to non-participating customers."[1] I also sponsored direct and surrebuttal testimony in DESC's 2021 annual fuel clause proceeding, Docket No. 2021-2-E, on how the value of distributed solar resources should be assessed in that cost recovery proceeding.

Q: ON WHOSE BEHALF ARE YOU TESTIFYING IN THIS PROCEEDING?

A: I am testifying on behalf of South Carolina Coastal Conservation League and Southern Alliance for Clean Energy.

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[1] See Order No. 2021-391, at p. 89.

II. SUMMARY OF TESTIMONY

Q: PLEASE SUMMARIZE YOUR TESTIMONY.

A: My testimony examines the values that DESC has calculated for distributed solar resources in this fuel cost recovery proceeding and evaluates whether those values comply with the requirements of S.C. Code §§ 58-27-865 and 58-40-20, and Commission Order Nos. 2015-194 and 2021-569. At a high level, I conclude that DESC significantly undervalues certain values of distributed solar, such as the avoided capacity costs for generation, transmission, and distribution. The utility also fails to recognize the increasingly important value of distributed renewables as a hedge against rising fossil fuel prices and the risks of carbon and methane emissions from burning those fuels.

This testimony first provides statutory and regulatory background on annual fuel cost proceedings under S.C. Code § 58-27-65 and the recovery of DER program costs pursuant to the cost-benefit methodology adopted in Order No. 2015-194, as amended recently by Order No. 2021-569. This section also observes that all benefits of DERs adopted in Order No. 2015-194 are quantifiable and that, in the event there is uncertainty about the magnitude of a specific benefit or cost, the default should not be to assign a zero value to that benefit or cost. Instead, the Commission should establish a reasonable value for the benefit or cost based on an examination of several cases that span a range of reasonable values for such a benefit or cost.

The second part of this testimony discusses my concerns with certain of the avoided cost components that DESC has proposed in the testimony of DESC witness Mr. James W.

Neely, and I recommend certain corrections and alternative approaches to these components. These include:

- Avoided energy costs should be differentiated on a seasonal and temporal basis, consistent with the approach that the Commission has adopted in Docket No. 2021-88-E concerning revisions to DESC's PR-1 and PR (Standard Offer) avoided cost rate schedules.
- Existing solar DERs allow DESC to avoid capacity costs for new generation at a level equal to 26.5% of the solar nameplate capacity.
- DESC's avoided generation capacity costs should be $180.61 per kW-year, in recognition that the utility has an immediate need for new capacity to replace retiring units.
- DESC's avoided transmission and distribution (T&D) capacity costs are $56.70 per kW-year for transmission and $88.10 per kW-year for distribution. These avoided costs for T&D capacity costs are calculated using the NERA regression method that determines the long-term relationship between DESC's T&D investments and its peak demands.
- Based on an analysis of DESC's loads at its transmission and distribution substations, distributed solar avoids T&D capacity costs equal to 29% of the solar nameplate for transmission and 31% for distribution.
- The 20-year levelized avoided costs associated with the risks of carbon regulation can be quantified from data in DESC's 2021 Integrated Resource Plan Update, at $0.0046 per kWh.

- Distributed renewable generation provides a long-term physical hedge against volatility in natural gas prices. This fuel hedge value can be quantified using a method developed for the Maine Public Utilities Commission. Recognizing this value is particularly important given the recent spikes in fossil fuel prices.
- The costs of integrating DERs should be reduced in recognition that only a portion of DER output is exported to the grid.
- Marginal line losses are greater than average losses by at least 50%. This approximation can be used until DESC's more rigorous line loss study is complete. Both energy and capacity losses should be included in the calculation of avoided line losses.

The following **Table ES-1** summarizes my recommended avoided cost values for solar DERs, for both the current period and on a 20-year levelized basis. The yellow-shaded rows are the components where my recommendations differ from those of DESC, as explained in this testimony.

Table ES-1: ***Recommended Total Value of NEM Distributed Energy Resources***

	Current Period *($/kWh)*	**20-Year Levelized** *($/kWh)*	**Components**
1	$0.0302	$0.0388	Avoided Energy Costs
2	$0.0322	$0.03217	Avoided Capacity Costs
3	$0.00000	$0.00000	Ancillary Services
4	$0.0257	$0.02970	T & D Capacity
5	$0.0000004	$0.0000002	Avoided Criteria Pollutants
6	$0.00000	$0.00463	Avoided CO_2 Emission Cost
7	$0.0020	$0.0221	Fuel Hedge
8	($0.0009)	($0.0009)	Utility Integration & Interconnection Costs
9	$0.00000	$0.00000	Utility Administration Costs
10	$0.00015	$0.00011	Environmental Costs
11	$0.0112	$0.0141	Avoided Line Losses
12	**$0.1005**	**$0.1406**	**Total Value of NEM DERs**

III. THE COST-BENEFIT METHODOLOGY IN ORDER NO. 2015-194

Q: PLEASE DESCRIBE THE EXISTING METHODOLOGY USED TO VALUE THE GENERATION OUTPUT OF DERS IN SOUTH CAROLINA.

A: In Order No. 2015-194, the Commission adopted a methodology that calculates the net value—i.e., the net benefits—of DER generation to determine the amount of under- or over-recovered revenue from the net metering customer. In the case of under-recovered revenue, utilities may recover the difference, referred to as the "DER NEM Incentive."[2] In the case of over-recovered revenue, utilities are directed to calculate the credit, if any, to be applied to a net metering customer.[3]

The methodology set out in Order No. 2015-194 to quantify the net benefits delivered by DERs is based on a "value stack" of costs that the utility will avoid (or, in a few instances, incur) as a result of using renewable DER generation in lieu of other generation sources. These are:

1. Avoided Energy
2. Energy Losses/Line Losses
3. Avoided Generation Capacity
4. Ancillary Services
5. Transmission and Distribution Capacity
6. Avoided Criteria Pollutants
7. Avoided Carbon Dioxide (CO_2) Emission Costs
8. Fuel Hedge
9. Utility Integration & Interconnection Costs
10. Utility Administration Costs
11. Environmental Costs

[2] *See* Order No. 2015-194 at pp. 19-22. As the Commission is aware, this framework for compensating net metering customers applies only to those net metering customers who apply before June 1, 2021. S.C. Code. Ann. § 58-40-20(B).
[3] *Id*. at 22.

The settlement adopted in the order included a narrative description of each of these value components. Order No. 2015-194 recognized that some of these values might be "placeholders" due to "a lack of capability to accurately quantify a particular category," but that these values would be updated when reasonable quantifications become available.[4]

Q: HOW DOES THIS METHODOLOGY APPLY TO THE PRESENT FUEL COST RECOVERY PROCEEDING?

A: Order No. 2015-914 provides that "the costs and benefits of net metering and the required amount of the DER NEM incentive shall be computed and updated annually coincident in time with the Utility's filing under the fuel clause."[5] Accordingly, the utility's annual fuel proceeding provides the occasion to quantify the net benefits of DERs, including distributed solar.

Importantly, there is an inverse relationship between the net benefits of DERs and the DER NEM incentive the utility collects from ratepayers, meaning that as the value of DER resources increases, the DER NEM incentive, and thus its impact on the fuel rider, *decreases*. As such, it is critically important to ensure that the benefits of DERs are accurately and fully accounted for to ensure ratepayers are not overpaying or subsidizing the utility on the basis of incorrect solar valuation.

Q: DO YOU HAVE ANY GENERAL OBSERVATIONS ON THE VALUE STACK OF BENEFITS ADOPTED IN ORDER NO. 2015-194, AND LISTED ABOVE?

[4] *Id.* at 20.
[5] *Id.* at 22.

A: Yes. All the categories of benefits and costs in this value stack are quantifiable and have been quantified in other NEM or distributed generation ("DG") benefit/cost studies. There are well-accepted techniques to perform these calculations, or reasonable values for these costs that can be derived from such studies performed for other utilities. If there is uncertainty about the magnitude of a specific benefit or cost, the default should not be to assign a zero value to that category, but to examine several cases that span a range of reasonable values for this benefit or cost and use that review to establish a reasonable value.

Q: DID THE COMMISSION IN ORDER NO. 2021-569 PROVIDE ADDITIONAL DIRECTION ON HOW TO CALCULATE THE BENEFITS INCLUDED IN THE VALUE STACK?

A: Yes. I will discuss and have incorporated the Commission's findings from Order No. 2021-569 in Section IV below, where I make recommendations regarding DESC's calculations of certain benefits in the value stack.

Q: SEVERAL OF THE BENEFITS INCLUDED IN THE VALUE STACK ADOPTED IN ORDER NO. 2015-194 – FOR EXAMPLE, AVOIDED CRITERIA POLLUTANTS AND AVOIDED CARBON DIOXIDE EMISSIONS – WILL HAVE SOCIETAL BENEFITS THAT EXTEND BEYOND DIRECT COMPLIANCE COSTS FOR RATEPAYERS. ARE THESE SOCIETAL BENEFITS QUANTIFIABLE?

A: Yes, they are. For example:

- Reductions in criteria air pollutants have health benefits that can be quantified using available models such as the U.S. Environmental Protection Agency's COBRA model.

- Damages from the climate-changing impacts of carbon dioxide emissions have been modeled by numerous researchers. Societal benefits should include a recent estimate of the amount by which these estimates of climate change damages exceed direct carbon compliance costs.
- Other quantifiable societal benefits include Avoided Methane Leakage, Land Use Benefits, and Economic Benefits.

My direct testimony filed in Docket No. 2019-182-E included an extensive discussion of the quantification of these societal benefits.[6] While I am not proposing that the Commission include these quantified societal benefits in the calculation of the net value of DER generation, I submit that it is important for the Commission to be mindful of these additional quantifiable benefits of DERs.

IV. <u>SELECTED CRITIQUE OF CERTAIN BENEFITS OF SOLAR DERS</u>

Q: WHICH COMPONENTS OF DESC'S CALCULATED AVOIDED COSTS FOR DISTRIBUTED SOLAR RESOURCES CONCERN YOU?

A: This section addresses issues I have identified with the following components of DESC's avoided costs:

- The time-differentiation of avoided energy costs;
- The contribution of solar to avoided generation capacity costs;
- Avoided costs for transmission and distribution (T&D);
- Avoided CO_2 emission costs;

[6] *See* Direct Testimony of R. Thomas Beach, Docket No. 2019-182-E, at p. 22 (discussing avoided methane leakage and land use benefits); see also Direct Testimony of Frank Hefner, Docket No. 2019-182-E (economic benefits); and Direct Testimony of Justin Barnes, Docket No. 2019-182-E (economic benefits).

- The value of distributed solar as a hedge against volatile fossil fuel costs;
- Utility integration & interconnection costs; and
- Energy losses / line losses.

A. <u>Time-Differentiation of Avoided Energy Costs</u>

Q: WHAT DOES ORDER NO. 2021-569 PROVIDE ABOUT HOW THE AVOIDED ENERGY COSTS OF DERS SHOULD BE CALCULATED?

A: In Order No. 2021-569, the Commission determined that the calculation of avoided energy costs should "include calculation of the seasonal and temporal (e.g., on-peak period value) variations in avoided energy cost."[7] The Commission made this determination recognizing that solar DERs produce power during the daylight hours and that solar output varies across the seasons of the year.[8]

Q: DID DESC INCLUDE SUCH TEMPORAL AND SEASONAL VARIATIONS IN AVOIDED ENERGY COSTS IN ITS AVOIDED ENERGY COST VALUE?

A: No, it did not. DESC provided in discovery that "it does not yet have the additional data necessary to reflect the temporal and seasonal variation in energy costs or to determine a per kWh average price for avoided energy costs based on daylight hours where solar is expected to operate."[9] This is surprising, given that the utility ran a production cost model (PLEXOS) to calculate avoided energy costs. To my knowledge, PLEXOS produces a marginal energy cost in every hour, which DESC could have used to determine "the temporal and seasonal variation in energy costs." DESC Witness Neely acknowledges this in his description of PLEXOS as a tool "which models the least-cost commitment and

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[7] Order No. 2021-569 at 36.
[8] *Id.*
[9] DESC Response to CCL/SACE Data Request (DR) No. 2, Q7, included in **Exhibit RTB-2**.

dispatch of generating units to serve load hour-by-hour."[10] However, DESC does not appear to have used these hourly PLEXOS marginal costs to comply with this provision of Order No. 2021-569.

Q: IS THERE ANOTHER DATA SOURCE THAT CAN BE USED TO ESTIMATE THE SEASONAL AND TIME-DIFFERENTIATED AVOIDED ENERGY COSTS FOR SOLAR RESOURCES?

A: Yes. The Commission has issued a directive order in Docket No. 2021-88-E concerning revisions to DESC's PR-1 and PR (Standard Offer) avoided cost rate schedules that would adopt avoided energy costs for these schedules based on 11 seasonal and time-of-use (TOU) periods, on a technology-neutral basis.[11] This seasonal and temporal differentiation of avoided energy costs also could be applied to the 7x24 baseload avoided energy costs that DESC has used in this proceeding. A typical solar profile from DESC's service territory then could be applied to the resulting seasonal and time-differentiated avoided energy costs, to determine solar-weighted avoided energy costs. This appears to me to be a straightforward means for DESC to comply with the Commission's direction in Order No. 2021-569.

B. Avoided Generation Capacity Costs

Q: PLEASE DISCUSS DESC'S ASSUMPTION FOR THE CONTRIBUTION OF SOLAR TO AVOIDING THE COSTS OF GENERATION CAPACITY.

[10] Neely Direct Testimony at 5.
[11] Commission Directive Order in Docket No. 2021-88-E (issued Nov. 16, 2021). As of the date of this filing, the final order in Docket No. 2021-88-E is pending.

A: DESC assumes a solar contribution to avoided generation capacity costs of just 3.423% of a solar system's nameplate capacity. This contribution is derived, according to Witness Neely, by "using the historical usage profiles to determine the annual capacity contribution from NEM customer-generators."[12] Witness Neely did not explain what "historical usage profiles" he used or how those profiles were used to determine the capacity that the customers' solar panels supply to the electric system.[13]

From Witness Neely's workpapers, it appears that he began with the utility's historical hourly load profile, then subtracted hourly utility-scale solar generation to derive a "net load" hourly profile. Next, he subtracted distributed solar output from the net load hourly profile to determine hourly "net net loads." In each day of the year, he then assigned a distributed solar capacity value equal to the difference between the maximum net load on that day and the maximum of the "net net" load. Finally, he averages these daily distributed solar capacity values across all days of the year and expresses them as a percent of the nameplate solar capacity. Across all days of the year, he calculates an average distributed solar capacity contribution of 3.423% of nameplate.

Q: WHAT ARE THE PROBLEMS WITH THIS APPROACH?

A: There are several significant issues. First, in Witness Neely's calculation of the capacity contribution of solar, each day of the year has the same weight as every other day. In reality, system loads vary significantly from day to day and season to season, and capacity typically has significant value only on those days with the highest loads. But in Witness

[12] Neely Direct Testimony, at pp. 9-10.
[13] The language that Witness Neely cites from Order No. 2021-569 in support of his approach deals with a cost-of-service analysis for customer-generators, not with the benefit of avoided generation capacity costs. The finding that Witness Neely cites from Order No. 2021-569 (Finding No. 10) is in the section on "Cost of Service Analysis."

Neely's calculations, the capacity contribution of solar counts as much on a spring day when peak demand is 3,000 MW as it does on a hot summer day when demand is 4,500 MW. Second, his use of the net loads that subtract utility-scale solar output from system loads gives an undue preference to the capacity contribution of utility-scale solar over distributed solar, and in effect assumes that utility-scale solar was deployed first, when both types of solar have developed simultaneously in recent years on the DESC system.

Q: WHAT DIRECTION DID ORDER NO. 2021-569 PROVIDE ON HOW TO CALCULATE THE CONTRIBUTION OF DISTRIBUTED SOLAR GENERATION TO AVOIDING THE COSTS OF GENERATION CAPACITY ON THE DESC SYSTEM?

A: Order No. 2021-569 states, on page 38, that "[t]he Commission also adopts Witness Beach's recommendation that forecasts of [avoided] capacity costs take into consideration the hours in which utility loads are likely to peak and when generation is most needed." Accordingly, the contribution of solar resources to avoiding generation capacity should look at the output of distributed solar systems in the hours of the year when loads are highest on the DESC system – these are the hours when generation capacity is most needed and most valuable. To implement this direction, I have applied and extended the approach that I used in Docket No. 2019-182-E, which considers solar output only in those hours when loads exceed 90% of the maximum hourly load for the year. For the load data, I use fifteen years of hourly DESC loads (2006 to 2020), as reported to FERC in Form 714. From this hourly load data, I developed a non-zero Peak Capacity Allocation Factor (PCAF) for each hour of each year in which the load exceeds 90% of the maximum hourly load for that year. The PCAF factors are weighted according to the amount by which they exceed the threshold of 90% of the maximum annual load. Thus, the hour with the highest PCAF is the hour with the maximum load for the year. Hours with loads at or below 90% of the annual maximum load have a PCAF of zero.

Due to the potential for both summer and winter peaks, it is important to look at a long-term period to capture the relative frequency of these seasonal peaks. That is why I used 15 years of historical hourly DESC loads. This PCAF analysis results in probability weights in each hour and month of the year, with the non-zero PCAF values concentrated on afternoon hours (from the summer months) and, to a lesser extent, on morning hours (from winter months), as shown in the heat map of PCAF factors in **Figure 1** below. The heat map shows a consistent allocation of generation PCAFs to the peak hours on summer afternoons, as well as a smaller and less frequent allocation in some years (for example, 2009, 2014, and 2018) to morning hours when there were cold snaps that caused demand to peak on winter mornings.

Figure 1: *Heat Map of DESC Generation PCAFs*

Hour / Year	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
1	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
2	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
3	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
4	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
5	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
6	0%	0%	0%	0%	0%	0%	0%	0%	1%	1%	0%	0%	2%	0%	0%
7	0%	0%	1%	6%	3%	1%	0%	0%	9%	6%	0%	0%	7%	0%	0%
8	0%	0%	2%	10%	6%	3%	1%	0%	19%	8%	0%	1%	11%	0%	0%
9	0%	0%	1%	5%	3%	2%	0%	0%	15%	4%	0%	1%	9%	0%	0%
10	0%	0%	0%	1%	0%	0%	0%	0%	4%	1%	0%	0%	4%	0%	0%
11	0%	1%	0%	0%	1%	0%	0%	0%	1%	0%	0%	0%	1%	0%	0%
12	5%	5%	0%	1%	4%	4%	3%	3%	0%	0%	1%	3%	1%	1%	2%
13	12%	12%	2%	6%	11%	10%	11%	9%	2%	6%	10%	8%	5%	8%	10%
14	21%	17%	9%	14%	17%	18%	19%	17%	6%	16%	18%	17%	10%	17%	16%
15	25%	20%	20%	20%	19%	21%	23%	23%	16%	21%	22%	22%	15%	24%	21%
16	20%	19%	24%	21%	18%	20%	20%	23%	18%	21%	22%	21%	16%	24%	21%
17	11%	13%	22%	12%	12%	14%	14%	16%	8%	12%	16%	15%	10%	17%	18%
18	4%	8%	13%	3%	5%	7%	8%	8%	2%	3%	8%	9%	4%	8%	10%
19	1%	3%	4%	0%	1%	1%	1%	1%	0%	0%	2%	2%	2%	1%	2%
20	0%	2%	1%	0%	0%	0%	0%	0%	0%	0%	0%	0%	1%	0%	0%
21	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	1%	0%	0%
22	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	1%	0%	0%
23	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
24	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%

Given the generation PCAF distribution in Figure 1, I then calculate the PCAF-weighted solar output for a typical distributed solar system in South Carolina, as a fraction of its unweighted output. The result is a solar PV capacity contribution of 45%, averaged across these 15 historical years.

Q: DESC NOW HAS AN APPRECIABLE AMOUNT OF BOTH UTILITY-SCALE AND DISTRIBUTED SOLAR ON ITS SYSTEM. YOUR CAPACITY CONTRIBUTION CALCULATED ABOVE IS BASED ON DESC'S GROSS LOAD PROFILE, WITHOUT CONSIDERING THE IMPACT OF THE EXISTING UTILITY-SCALE SOLAR ON THE NET LOADS (GROSS LOADS MINUS SOLAR) THAT DESC MUST SERVE WITH OTHER RESOURCES. WOULDN'T THE CAPACITY CONTRIBUTION OF SOLAR BASED ON NET LOADS BE LOWER?

A: Yes. A 90% PCAF calculation based on net loads, using the net load data in Witness Neely's workpapers, produces a significant lower solar capacity contribution of 7.9% of the solar nameplate.

Q: HOW DO YOU RECONCILE THESE TWO DIFFERENT RESULTS?

A: The solar capacity contribution of 45% based on <u>gross</u> loads in essence represents the capacity contribution of the first MW of existing distributed solar added to the system; the capacity contribution of 7.9% based on <u>net</u> loads represents the capacity contribution of the last MW of existing distributed solar added. The task here is to capture the average capacity contribution of all existing distributed solar resources, which have been added to the DESC system over time. A reasonable way to capture this average capacity contribution is to use a compromise between the two approaches based on the average of the results of the two methods using gross and net loads, as a measure of the average capacity contribution of the existing distributed solar resources on the DESC system. This average is 26.5% of solar nameplate.

Thus, I recommend that 26.5% of a solar PV project's capacity may be assumed to contribute to meeting DESC's capacity needs in its peak load hours.

Q: YOU CRITICIZE WITNESS NEELY'S SOLAR CAPACITY CONTRIBUTION FOR NOT FOCUSING ON HIGH-DEMAND HOURS AND FOR USING NET LOADS BASED ON DESC'S ENTIRE UTILITY-SCALE SOLAR GENERATION. WHAT WOULD BE THE RESULT OF HIS METHOD IF THESE ISSUES ARE CORRECTED?

A: I have recalculated his results to address both issues. First, I have only used days that have a peak hourly net load that is within 10% of the system annual peak hourly net load. Second, I reduce his utility-scale solar generation by 50%, as a compromise between an approach using gross loads and one using net loads based on 100% of DESC's existing utility-scale solar. The result of his method under those assumptions is a solar capacity contribution of 22.2%. This is relatively close to the 26.5% capacity contribution using my PCAF approach.

Q: DESC'S INTEGRATED RESOURCE PLAN (IRP) USES A CAPACITY CONTRIBUTION FROM NEW SOLAR RESOURCES OF JUST 4.25% OF NAMEPLATE, BASED ON YET ANOTHER METHOD – AN EFFECTIVE LOAD CARRYING CAPACITY (ELCC) CALCULATION. WHY WOULD IT NOT BE APPROPRIATE TO USE THIS ELCC VALUE?

A: The issue with the IRP's ELCC is that it applies only to new solar resources. The purpose of calculating the value of DERs in this fuel clause case is to capture the capacity contribution of the existing fleet of distributed solar resources, not the contribution of solar resources that may be added in the future. As noted in Witness Neely's testimony, the recovery of the DER NEM Incentive calculated in this fuel clause proceeding applies only to customer-generators who apply before June 1, 2021. After that date, the Solar Choice tariffs will apply.[14]

[14] Neely Direct Testimony, at p. 18.

Q: DESC WITNESS NEELY ASSERTS THAT DESC'S CURRENT PERIOD AVOIDED GENERATION CAPACITY COSTS ARE ZERO, BECAUSE DESC HAS NO IMMEDIATE NEED FOR CAPACITY.[15] DO YOU AGREE?

A: No. DESC's 2021 IRP Update shows that the utility is currently planning to replace 10 aging combustion turbines and a conventional gas-fired steam boiler with five new aeroderivative CT units.[16] Approximately half of this capacity has been agreed to by settling parties via a partial settlement recently approved by the Commission in Docket No. 2021-93-E.[17] It is my understanding that DESC has proposed for the first of these near-term replacements go into service in 2023.[18] DESC clearly requires the new CT units to meet its near-term capacity needs. Thus, the utility has a need for new capacity as early as 2023 – it does not matter whether this need is due to load growth or, as in this case, plant retirements.

Q: DESC USES A 20-YEAR AVOIDED GENERATION CAPACITY COST OF $87.73 PER KW-YEAR BASED ON THE 20-YEAR LEVELIZED COST OF A NEW AERO-DERIVATIVE COMBUSTION TURBINE. DO YOU HAVE ANY COMMENTS ON THIS CALCULATION?

A: This calculation assumes that the new CT is installed in 2028. As noted above, DESC is adding CT capacity as soon as next year, to meet the shortfall in capacity resulting from retiring aging generation. As a result, the avoided generation capacity cost should be based

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[15] Neely Direct Testimony, at p. 9: "There are no capacity needs until 2028 therefor [sic] the Current Period avoided Capacity is zero."
[16] See DESC 2021 IRP Update at 20-22, describing its CT Replacement Plan.
[17] See Partial Settlement Agreement in Docket No. 2021-93-E; Order No. 2022-27, Order Approving Partial Settlement Agreement, Docket No. 2021-93-E (Jan. 11, 2022).
[18] Direct Testimony of Andrew Walker, Docket No. 2021-93-E, at pp. 35, 38.

on CT costs in 2023, not CT costs in 2028. Using DESC's workpapers for CT capacity costs with the CT additions advanced to 2023, the 20-year levelized capacity costs of a new 105 MW aeroderivative CT in 2023 is $180.61 per kW-year.

Q: DESC WITNESS NEELY CALCULATES THE AVOIDED COST COMPONENT FOR GENERATION CAPACITY BY MULTIPLYING THE SOLAR CAPACITY CONTRIBUTION OF 3.423% BY THE AVOIDED CT COST, THEN DIVIDING BY 8760 HOURS PER YEAR.[19] IS THIS CORRECT?

A: No, it is not. The solar capacity contribution represents the capacity that a solar project can avoid, as a percentage of a solar project's nameplate capacity. This percentage contribution is then multiplied by the avoided cost of generation capacity, to determine the annual dollars avoided by one kW of solar nameplate. To determine the avoided costs per kWh of solar output, the denominator of the calculation should thus be the annual solar output, in annual kWh of solar production per kW of nameplate. The denominator should not be the number of hours in a year (8760 hours). Witness Neely's use of 8760 hours in the denominator mistakenly assumes that a solar unit operates at full nameplate capacity in all hours of the year.

Q: WHAT ARE YOUR CALCULATED AVOIDED GENERATION CAPACITY COSTS, BOTH IN THE CURRENT PERIOD AND AS LONG-TERM 20-YEAR LEVELIZED COSTS?

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[19] Neely Direct Testimony, at p. 9.

A: Given DESC's immediate need for new capacity, as well as the use of 20-year levelized CT costs to value capacity in the year of first need, the current and 20-year levelized avoided generation capacity costs are the same. My calculation is shown in **Table 1**.

Table 1: *Avoided Generation Capacity Costs*

line	**Component**	**Value**	***Notes***
A	Annual Cost of New Capacity ($/kW-year)	180.61	*CTs installed in 2022*
B	Plus 14% Summer Reserve Margin ($/kW-year)	205.90	*2021 IRP, at p. 32*
C	Solar Capacity Contribution	26.7%	*PCAF Analysis*
D	Avoided Generation Capacity ($/kW-year)	54.97	*B x C*
E	Solar Annual Output (kWh per kW)	1,709	*PVWATTS Charleston*
F	Avoided Generation Capacity Costs ($/kWh)	0.032	*D / E*

C. <u>Avoided T&D Costs</u>

Q: HOW DID YOU DETERMINE THE CONTRIBUTION OF SOLAR OUTPUT TO AVOIDED TRANSMISSION AND DISTRIBUTION (T&D) SYSTEM CAPACITY COSTS?

A: Solar avoids transmission and distribution (T&D) investments by reducing peak loads on the DESC T&D system. Similar to my PCAF analysis for the generation capacity contributions from solar PV, I performed PCAF analyses based on transmission system and distribution system hourly loads provided by DESC. This load data includes hourly loads at each DESC transmission and distribution substation.[20] Compared to my PCAF

[20] The inputs to the PCAF analyses I performed for transmission and distribution were, respectively, DESC's hourly transmission bank and distribution substation loads. I calculated a weighted average transmission PCAF by weighting the PCAF allocations for each transmission bank by its maximum load; similarly, the distribution PCAF allocation weighted the PCAF allocations for each distribution substation according to the DESC-indicated capacity of each distribution substation.

analysis of the solar contribution to generation capacity (which was based on system load data), the T&D PCAF analyses show similar solar capacity contributions of 29% for transmission and 31% for distribution.

To estimate the marginal cost of T&D capacity, I have used the well-accepted National Economic Research Associates (NERA) regression method. This approach is used by many utilities to determine their marginal transmission and distribution capacity costs that vary with changes in load.[21] The NERA regression model fits incremental T&D investment costs to peak load growth. The slope of the resulting regression line provides an estimate of the marginal cost of T&D investments associated with changes in peak demand.[22] To capture long-run marginal costs, the NERA methodology typically uses at least 15 years of data on T&D investments and peak transmission system loads. This data is historical data reported in FERC Form 1, plus a current forecast of future investments and expected load growth if available. I have utilized NERA regressions based on DESC's historical peak load growth and transmission and distribution investments over the period from 2009 to 2025, using DESC's FERC Form 1 data for the historical portion of this period through 2020, as well as a five-year forecast of T&D investments and load growth (2021-2025). I add loaders for the operations and maintenance (O&M) and administration, and general (A&G) costs associated with these investments in T&D rate base. These

[21] For example, both Southern California Edison and San Diego Gas & Electric have used the NERA regression method for many years to calculate their marginal distribution costs. For a detailed explanation of this approach, see Southern California Edison's testimony in CPUC Docket A. 17-06-001, Exhibit SCE-02, at pp. 36-38.
[22] It is important to keep in mind that peak load growth is a proxy for growth in T&D capacity. Some utilities – for example, Southern California Edison – track their T&D system capacity over time and use this data directly in the regression.

loaders are based on Form 1 data on T&D O&M and A&G costs as percentages of rate base investments.

The testimony of Brian Horii for the Office of Regulatory Staff (ORS) in Docket 2019-182-E observed that such regressions based on coincident peak demand overstate marginal T&D costs, because the sum of the noncoincident peak loads on the elements of the T&D system that drive investments are higher than the coincident system peak loads used in the denominator of marginal T&D costs.[23] I agree that this observation has merit, particularly given that my PCAF analysis also looks at a range of hours with loads within 10% of the peak hour, and not just at the peak hour. Accordingly, I have included 28% and 23% downward adjustments to the avoided transmission and distribution capacity costs, respectively, to recognize that marginal T&D costs per unit of noncoincident peak loads on the T&D systems are lower than the marginal T&D costs per unit of coincident system peak loads. DESC's distribution load data indicates that the coincident system peak load is 23% lower than the sum of noncoincident peak distribution substation loads. Similarly, the coincident peak load on the transmission system is 28% lower than the sum of non-coincident transmission bank peak loads. My analysis results in dollars per kW values for avoided T&D capacity, which I annualize using a real economic carrying charge (RECC) factor. I then multiply these annualized values by the PCAF-based solar contribution to avoiding T&D capacity. Finally, to express this avoided transmission cost on the basis of dollars per MWh of solar output, I divide by the expected annual output of

[23] *See* Direct Testimony of Brian Horii for S.C. Office of Regulatory Staff, Docket No. 2019-182-E, at 29-30.

distributed solar PV, in kWh per kW. The following **Tables 2 and 3** show the results of my calculation of DESC's current avoided T&D capacity costs.

Table 2: *Avoided Transmission Capacity Costs*

Line	**Component**	**Value**	***Notes***
A	Avoided Transmission Capacity ($/kW-year)	56.70	*NERA method*
B	Solar Capacity Contribution	29.2%	*PCAF method*
C	Solar Annual Output (kWh per kW)	1,709	*From PVWATTS*
D	Current Avoided Transmission Capacity ($/kWh)	0.0097	*A x B / C*
E	20-year Avoided Transmission Capacity ($/kWh)	0.0112	*D x 1.15*

Table 3: *Avoided Distribution Capacity Costs*

Line	**Component**	**Value**	***Notes***
A	Avoided Distribution Capacity ($/kW-year)	88.10	*NERA method*
B	Solar Capacity Contribution	31.1%	*PCAF method*
C	Solar Annual Output (kWh per kW)	1,709	*From PVWATTS*
D	Current Avoided Distribution Capacity ($/kWh)	0.0160	*A x B / C*
E	20-year Avoided Distribution Capacity ($/kWh)	0.0185	*D x 1.15*

The sum of these current avoided transmission and distribution costs is $0.0257 per kWh. To derive the 20-year avoided T&D capacity costs, I assume these costs will increase with inflation and then levelize them over 20 years at an 8.0% discount rate. These 20-year values are shown in the bottom lines of Tables 2 and 3; they total $0.0297 per kWh.

Q: PLEASE CRITIQUE THE UTILITY'S CALCULATION OF AVOIDED T&D COSTS.

A: DESC Witness Neely asserts, without support, that the utility's current avoided T&D costs are zero. Yet he calculates a positive value for avoided T&D costs over the next five years, based on DESC's T&D spending plan. His testimony does not explain why the utility's avoided T&D costs are zero today but will materialize in the next 5 years. For example, if

DESC's avoided T&D costs are zero today, that should be documented in a past T&D spending plan that covers 2022 and that shows that none of the investments in that plan were avoidable. In contrast, the NERA regression analysis that I provide above shows a strong long-term correlation between peak demand on the DESC system and the utility's investments in T&D, over a 15-year period from 2009 to 2025 – i.e., ten years of actual T&D investments and the next five years of forecasted spending – that includes the present moment. This long-term calculation of marginal/avoided T&D costs is a rigorous estimate of how the utility's T&D investments change as a function of the peak demand that DESC serves. To the extent that DERs can reduce DESC's peak demand, DERs will avoid capacity-related T&D costs. It is a reasonable estimate of the utility's current avoided costs for T&D capacity.

Witness Neely's testimony also does not discuss how he estimated that DESC's annual average "avoidable" T&D costs over the next five years are $1.3 million for transmission and $3.2 million for distribution. The problem with an engineering estimate of "avoidable" T&D costs is that it requires an arbitrary segregation of which T&D projects are capacity-related and which are not. In reality, a transmission or distribution addition can have multiple purposes – for example, a transmission or distribution project can both address a reliability issue <u>and</u> result in an expansion of system capacity. A project to replace old equipment may not be categorized as capacity-related but may be necessary to prevent the system's capacity from declining and thus have a capacity-related purpose as well. Using a NERA regression analysis, as I recommend, avoids having to make such arbitrary determinations, by developing an overall, "top-down," long-term relationship between all T&D investments and peak demand.

D. Avoided Costs of CO_2 Emissions

Q: ORDER NO. 2021-569 FOUND THAT THE DER VALUE STACK SHOULD INCLUDE THE AVOIDED COSTS FROM REDUCTIONS IN CARBON DIOXIDE AND METHANE EMISSIONS, PROVIDED THAT STATE OF FEDERAL LAWS IMPOSE REGULATORY BURDENS THAT RESULT IN REDUCTIONS IN SUCH EMISSIONS.[24] DO SUCH BURDENS EXIST?

A: Yes. The Energy Freedom Act in South Carolina, in particular Section 58-37-40, requires utilities to plan their resource portfolios considering, among other factors, "sensitivity analyses related to fuel costs, environmental regulations, and other uncertainties or risks." Due to the high likelihood of future regulations on carbon emissions, among other factors, DESC and the other South Carolina utilities are actively planning to reduce their carbon emissions, in order to mitigate the risk of having to take more drastic – and likely more expensive – future actions to reduce emissions.[25] For DESC, as for most other utilities in the U.S., the need to reduce carbon emissions constitutes one of the principal "uncertainties or risks" that it faces, even though only a subset of states (not including South Carolina) have moved thus far to regulate GHG emissions from utilities. Indeed, DESC in its 2021 IRP Update acknowledges that reducing future carbon emissions is a significant driver of its plan and it is planning and spending money today to reduce its carbon emissions. DESC states in its 2021 IRP Update that "[g]oing forward, the single most important

[24] See Order No. 2021-569 at pp. 12-13 (Finding 18).
[25] DESC's parent company Dominion Energy has made a corporate commitment to achieve net-zero carbon and methane emissions by 2050. See DESC 2021 IRP Update at p. 6.

environmental challenge for electric generation will be limiting carbon emissions."[26] Indeed, level of future CO_2 emissions is the second metric, after cost, that DESC used to evaluate resource scenarios in its 2021 IRP Update.[27]

Q: HAVE YOU CALCULATED THE AVOIDED CARBON BENEFIT FOR DESC?

A: Yes. DESC's 2021 IRP Update uses three carbon cost scenarios; the mid-range scenario assumes carbon costs of $12 per short ton in nominal dollars beginning in 2030 and escalating at 10% per year.[28] Under this scenario, the current period component for avoided carbon emission costs is zero. This mid-range scenario can be used to calculate a 20-year avoided cost for carbon and methane emissions. I use the conversion factor that burning an MMBtu of natural gas produces 117 pounds of CO_2 and assume that 1.9% of the methane burned in electric power plants is leaked to the atmosphere in the upstream production and pipeline infrastructure.[29] DESC's mid-range IRP assumption for GHG costs is equivalent to approximately a $0.71 per MMBtu added to the long-term, 20-year levelized cost of natural gas. Assuming a 6,500 Btu/kWh marginal system heat rate, this component becomes $0.0046 per kWh on a 20-year levelized basis.

Should the Commission not adopt this figure because there is not yet direct carbon regulation in South Carolina, I recommend that the Commission nevertheless factor avoided GHG emissions into its decision qualitatively. The Commission should recognize

[26] *Id*. at p. 45.
[27] See DESC 2021 IRP Update pp. 39-40. The IRP Update notes that consideration of CO_2 emissions is appropriate given that "Section 58-37-40(C)(2)(c) requires the Commission to consider, in its discretion, whether an IRP appropriately balanced the factor of compliance with applicable state and federal environmental regulations."
[28] *Id*. at pp. 37-38.
[29] See Alvarez *et al*.. "Assessment of methane emissions from the U.S. oil and gas supply chain," *Science*, June 2018, Vol. 361, Issue 6398, at pp. 186-188. This reports average U.S. methane leakage at 2.3% of consumption, with 85% (1.9%) attributed to sources upstream of large customers such as gas-fired power plants. A 20-year global warming potential for methane of 72 is assumed.

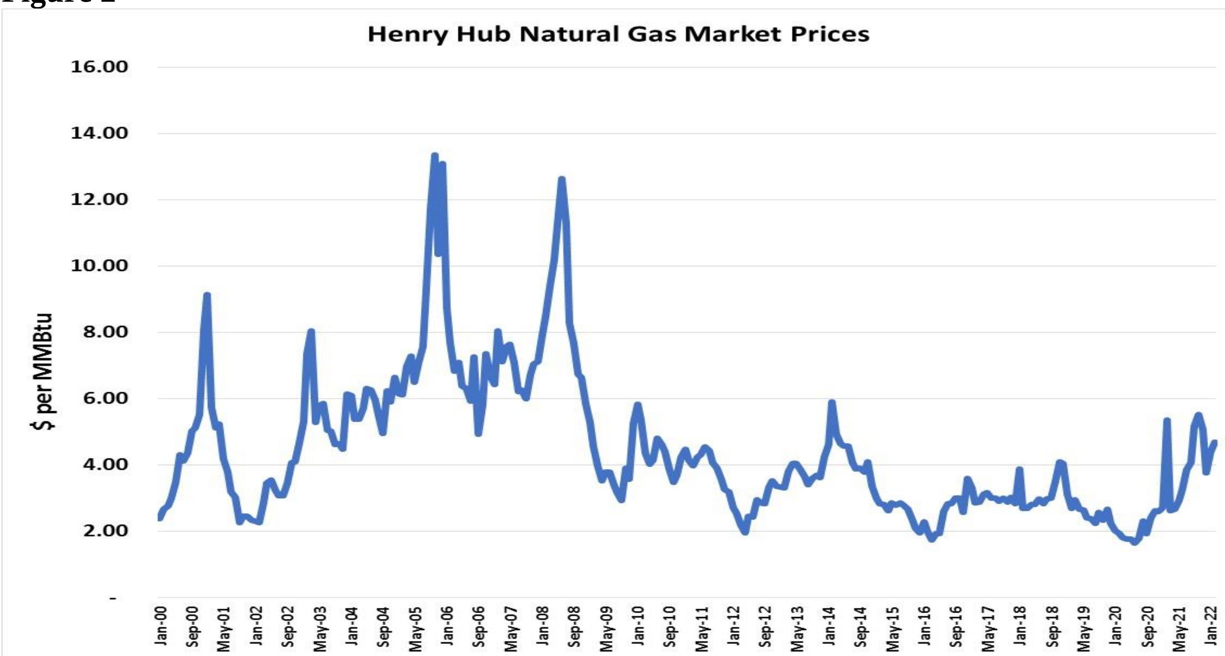
that utility expenditures to reduce carbon emissions are, in reality, non-zero, and thus a zero value for this component results in an overall underestimate of the value of distributed solar resources.

E. <u>Fuel Hedge Value</u>

Q: DESC WITNESS NEELY TESTIFIES THAT "DESC DOES NOT HEDGE FUELS FOR ELECTRIC GENERATION," AND THUS HE PROPOSES A ZERO VALUE FOR THE FUEL HEDGE BENEFIT OF DISTRIBUTED SOLAR. PLEASE RESPOND.

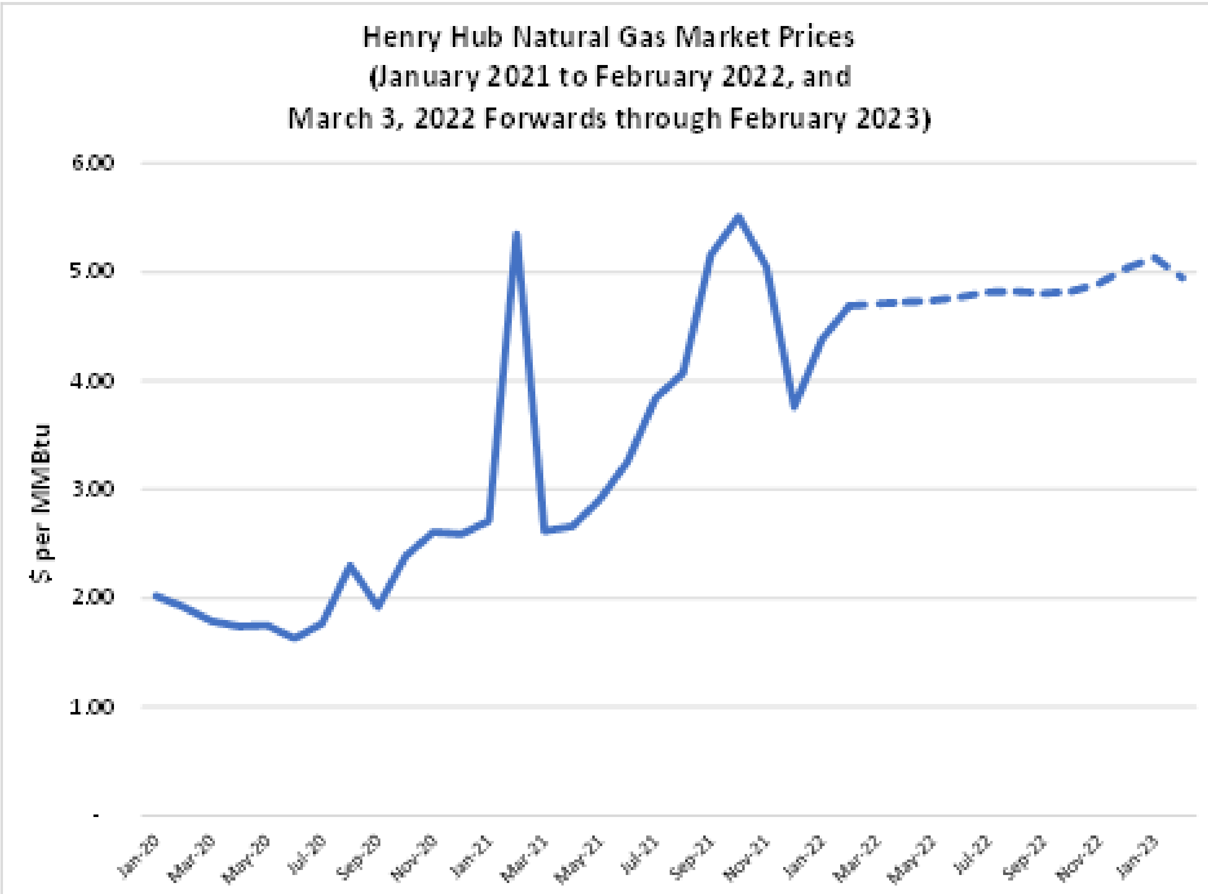
A: DESC may not have a program to use forward markets to hedge financially the costs of its purchases of fossil fuels, but it engages in long-term, physical hedging through all of its programs to develop renewable generation that will displace the use of fossil fuels. Renewable generation, such as solar PV, reduces a utility's use of natural gas, and thus decreases the exposure of ratepayers to the volatility and periodic spikes in natural gas prices. Such spikes have occurred regularly over the last several decades, as shown in the plot of historical benchmark Henry Hub gas prices in **Figure 2** below. In recent months, this value has been underscored by current events that have caused a worldwide spike in fossil fuel prices. This most recent spike in natural gas prices, over the 2021 forecast period for this case, is shown in **Figure 3** below. The dashed line in this figure also shows current forward gas prices for the next 12 months to February 2023. For DESC, this volatility in natural gas prices has caused a 26% increase in the fuel rider in this case, with this increase constituting the lion's share of a 6% increase in overall electric rates for residential customers.[30] This increase would have been greater absent the non-fossil generation – including utility-scale and distributed renewable generation as well as DESC's nuclear and hydro generation – on the DESC system. As a result, ratepayers realize a significant hedge value to any deployment on the DESC system of renewable resources that have zero fuel costs.

Figure 2



[30] Rooks Direct Testimony pp. 4-5 and Exhibits AWR-1 and AWR-2 (showing an increase in the DESC Base fuel Component from 2.413 cents/kWh to 3.032 cents/kWh (+26%)). The rate impacts of this increase are reported on page 16 of Witness Rooks' testimony.

Figure 3



Renewable generation provides a long-term hedge against volatile fuel costs for the entire 20-year economic life of, for example, a rooftop solar unit. Calculations of this component often underestimate this benefit by focusing on the costs of existing utility hedging programs. These programs only reduce the volatility in short-term fuel and purchased power expenses for the next one to three years. In contrast, there are substantial financial costs to establish a long-term hedge equivalent to what renewable generation provides.

Q: **HOW WOULD YOU CALCULATE THE FUEL HEDGE BENEFIT?**

A: To calculate this benefit, I use the methodology developed in the Maine Distributed Solar Valuation Study (Maine Study), a 2015 study commissioned by the Maine Public Utilities

Commission and authored by Clean Power Research. This approach recognizes that one could contract for future natural gas supplies today, and then set aside in risk-free investments the money needed to buy that gas in the future. This would eliminate the uncertainty in future gas costs. The additional cost of this approach compared to purchasing gas on a "pay as you go" basis (and using the money saved for alternative investments) is the benefit of reducing the uncertainty in the costs for the fuel that solar PV displaces.

I have performed this calculation for DESC, using a Henry Hub forecast of natural gas prices that employs current forward prices for three years (2022-2024), then transitions to the Energy Information Administration's 2022 Annual Energy Outlook long-term fundamentals forecast. The calculation also uses U.S. Treasuries (at current yields) as the risk-free investments and a marginal heat rate of 6,500 Btu per kWh. The result is a value of $0.0221 per kWh as the 20-year levelized benefit of reducing fuel price uncertainty. Short-term hedge transactions do not capture this long-term fuel hedge value, given that short-run price volatility (i.e., in the next 12-months or next 3-5 years) is not the same as price volatility over a 20-year period. For example, highly liquid futures markets do not exist over a 20-year timeframe, because of the significant costs and risks involved. Instead, ratepayers bear these risks and costs over the life of a fossil-fueled resource whose fuel costs are volatile because ratepayers ultimately "pay as you go" at the prevailing market price for fuel. Renewable generation provides a significant benefit to ratepayers by eliminating the long-term risks of this volatility. The one-year fuel hedge value is, of course, much lower, just $0.002 per kWh in our calculation.

F. Utility Integration & Interconnection Costs

Q: DO YOU ACCEPT WITNESS NEELY'S VALUE OF $0.0018 PER KWH FOR UTILITY INTERCONNECTION & INTEGRATION COSTS?

A: While I accept the solar integration costs of $0.0018 per kWh adopted in Docket No. 2021-88-E, Order No. 2021-569 specifies that, for purposes of the NEM Methodology value stack, this cost component is supposed to apply only to power that solar customers export.[31] Assuming conservatively that 50% of solar output is exported, this cost component per unit of total solar output should be $0.0009 per kWh, not the $0.0018 per kWh shown in Table 2 of Witness Neely's testimony.

G. Line Losses

Q: DO YOU HAVE ANY CONCERNS WITH DESC'S CALCULATION OF THE LINE LOSSES AVOIDED BY DERS?

A: Yes. I agree with the finding in Order No. 2021-569 that "[t]he best practice is to calculate avoided line losses on a marginal basis considering only daylight hours (when solar PV produces)."[32] I also agree conceptually with DESC Witness Neely that the goal should be that "[t]he loss factor used for these NEM values represents the cumulative marginal line losses at a residential customer's meter."[33] However, it is not clear that DESC is using marginal losses in all cases. For example, DESC assumes that average transmission losses are representative of marginal transmission losses,[34] when generally marginal losses are at

[31] Order No. 2021-569 at 13 (Finding No. 22).
[32] *Id*. at 13 (Finding No. 13).
[33] Neely Direct Testimony at 16.
[34] *Id*. at 17 ("DESC proposes to continue to apply its current approach to determine transmission losses, where marginal losses are equal to average losses.").

least 50% greater than average losses.[35] DESC does assume that marginal distribution losses are two times average losses. In addition, DESC has not yet developed loss factors based on load levels or time-of-day, although it has developed a detailed study plan to do so.[36] Finally, DESC applies its line loss adjustment to all components of the value of solar. I believe that this overstates the line loss adjustment, which should apply only to the energy- or capacity-related value components. Until more detailed analysis is available on DESC's T&D losses by load level and time-of-day, I recommend the following changes to DESC's calculation of avoided line losses:

- Assume that both marginal transmission and distribution losses are 50% higher than average losses.
- Apply energy losses to the energy or fuel-related avoided cost components, i.e., to the avoided energy and fuel hedge costs.
- Apply both transmission and distribution capacity losses to avoided generation and transmission capacity costs but apply only avoided distribution capacity losses to avoided distribution capacity costs.

The line loss component presented in the summary **Table 4** below includes these changes to the line loss calculations.

H. <u>Summary of Recommended Value Stack</u>

[35] The Regulatory Assistance Project has studied the relationship of marginal vs. average line losses for demand-side resources. *See* Regulatory Assistance Project, *Valuing the Contribution of Energy Efficiency to Avoided Marginal Line Losses and Reserve Requirements* (August 2011), at p. 5. See http://www.raponline.org/wp-content/uploads/2016/05/rap-lazar-eeandlinelosses-2011-08-17.pdf.

[36] Neely Direct Testimony at 16-18 (proposing to develop T&D "loss curves" based on load levels and/or season and time-of-day).

Q: PLEASE SUMMARIZE YOUR RECOMMENDATIONS FOR THE SOLAR DER VALUE STACK THAT THE COMMISSION SHOULD ADOPT, BOTH FOR THE CURRENT PERIOD AND FOR THE NEXT 20 YEARS.

A: My recommendations presented in this testimony are summarized in **Table 4** below. The yellow-shaded rows are the components where my recommendations differ from those of DESC, as explained in this testimony.

Table 4: ***Recommended Total Value of NEM Distributed Energy Resources***

	Current Period *($/kWh)*	**20-Year Levelized** *($/kWh)*	**Components**
1	$0.0302	$0.0388	Avoided Energy Costs
2	$0.0322	$0.0322	Avoided Capacity Costs
3	$0.00000	$0.00000	Ancillary Services
4	$0.0257	$0.0297	T & D Capacity
5	$0.0000004	$0.0000002	Avoided Criteria Pollutants
6	$0.0000	$0.0046	Avoided CO_2 Emission Cost
7	$0.0020	$0.0221	Fuel Hedge
8	($0.0009)	($0.0009)	Utility Integration & Interconnection Costs
9	$0.00000	$0.00000	Utility Administration Costs
10	$0.0002	$0.0001	Environmental Costs
11	$0.0112	$0.0141	Avoided Line Losses
12	**$0.1005**	**$0.1406**	**Total Value of NEM DERs**

V. <u>CONCLUSION</u>

Q: DOES THIS CONCLUDE YOUR TESTIMONY?

A: Yes.